

**STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL**

**TECHNICAL SUPPORT DOCUMENT FOR
PREVENTION OF SIGNIFICANT DETERIORATION AND
NOTICE OF CONSTRUCTION PERMIT
BP Cherry Point Cogeneration Project NO. EFSEC/2002-01
Whatcom County, Washington
November 7, 2003**

1. INTRODUCTION

1.1. The Permitting Process

1.1.1. The Prevention of Significant Deterioration Process

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of Federal Regulations (CFR), Part 52.21. Federal rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new source. The program limits degradation of air quality to that which is not considered "significant." It also sets up a mechanism for evaluating the effect that the proposed emissions might have on environmentally related areas for such parameters as visibility, soils, and vegetation. PSD rules also require the utilization of the most effective air pollution control equipment and procedures, after considering environmental, economic, and energy factors.

The Washington State Energy Facility Site Evaluation Council (EFSEC) is the PSD permitting authority for new thermal energy facilities with a net electrical output greater 350 Megawatts (MW), sited in the state of Washington, per Chapter 80.50 of the Revised Code of Washington (RCW) and Chapter 463-39 of the Washington Administrative Code (WAC).

1.1.2. The Notice of Construction Process

The procedure for issuing a Notice of Construction (NOC) permit is established in Chapter 70.94 Revised Code of Washington. Chapter 173-400 WAC and Chapter 173-460 WAC, require all new or modified stationary sources of air pollution to file a NOC application and receive an order of approval, prior to establishing a new or modified stationary source.

WAC 173-400-110 (new source review) outlines the procedures for permitting criteria pollutants. These procedures are further refined in WAC 173-400-113 (requirements for new sources on attainment or unclassifiable areas).

WAC 173-460-040 (new source review) supplements the requirements contained in Chapter 173-400 WAC by adding additional requirements for sources of toxic air pollutants.

EFSEC is the NOC permitting authority for energy facilities greater than 350 MW sited in the State of Washington as defined in Chapter 463-39 WAC, and Chapter 80.50 RCW.

1.1.3. Federal Regulations Summary

This permit may not contain all the requirements included in the following summary, however after the Title V and Acid Rain permits are issued each of the following regulations will be addressed.

Prevention of Significant Deterioration	40 CFR 52.21
New Source Performance Standards (NSPS)	40 CFR 60, subpart GG
NSPS	40 CFR 60, Subpart Db
NSPS Quality Assurance Procedures	40 CFR 60 Appendix F
NSPS Performance Specifications	40 CFR 60, Appendix B
National Emission Standards for Hazardous Air Pollutants (NESHAP)	40 CFR 63 Subpart YYYY
Acid Rain Permitting	40 CFR 72
Emissions Monitoring and Permitting	40 CFR 75
NO _x Requirements	40 CFR 76
Sulfur Content of Natural Gas to be monitored	40 CFR 60.334(b), 40 CFR 72.2, and 40 CFR 75, Appendix D

1.1.4. State Regulation Summary

This permit may not contain all the requirements included in the following summary, however after the Title V and Acid Rain permits are issued each of the following regulations will be addressed.

General and Operating Permit Regulations for Air Polluting Sources	Chapter 463-39 WAC
General Regulations for Air Pollution Sources	Chapter 173-400 WAC
Operating Permit Regulations	Chapter 173-401 WAC
Acid Rain Regulations	Chapter 173-406 WAC
Controls For New Sources of Toxic Air Pollutants	Chapter 173-460 WAC

1.2. The Project

1.2.1. The Site

BP West Coast Products, LLC, a wholly-owned subsidiary of BP, PLC, proposes to construct a 720-megawatt power cogeneration facility in northwestern Whatcom County, Washington. The BP Cherry Point Cogeneration Project (Project) would be located at the BP Cherry Point Refinery (Refinery), which is 6 miles northwest of Ferndale, 7 miles southeast of Blaine and about 15 miles north of Bellingham (T39N, R1E, S8, with UTM 10 520300E and 5415000N). The nearest community is Birch Bay, located about 2 miles northwest of the site. The Canadian border is about 8 miles directly north of the proposed site.

The Cogeneration Project would be sited adjacent to the northeast corner of the Refinery. The project, including the generation plant and support facilities, the new transmission line, natural gas and water supply lines, and construction laydown areas would be on BP Refinery owned property. This area is within the Cherry Point Major Industrial Urban Growth Area/Port Industrial Zone as defined in the Whatcom County Comprehensive Plan, issued May 20, 1997. The entire project area is zoned Heavy Impact Industrial. The Cogeneration Project site would occupy 33.17 acres of unimproved land.

The land surrounding the proposed Cogeneration Project is relatively flat and owned by BP for at least 0.5 miles in all directions. The closest residence is about 0.75 miles north and east of the proposed

Cogeneration Project. Industries in the area other than the Refinery include the Chemco plant located about 0.75 miles east of the project site and the Praxair plant located 0.75 miles south of the project site.

1.2.2. The BP Cogeneration Project

The Cogeneration Project would produce a nominal 720 megawatts (MW). The Project would export a maximum of about 85 MW of electricity and an expected maximum of 510,000 pounds per hour of steam to the Refinery. The 635 MW of power generated in excess of Refinery consumption would be exported via a new transmission line connected to the 230 kV BPA transmission line adjacent to the BP property.

The Project would be configured with three natural gas fired General Electric 7FA combustion gas turbines (CGTs), each with its own 173 MW electric generator. Each CGT would be equipped with a heat recovery steam generator (HRSG). Each HRSG would contain supplemental duct firing capability of up to 105 million BTU/hr. Steam produced from the three HRSGs would be sent to a single 223 MW steam turbine electric generator (STG) as well as to the Refinery. Each HRSG will be equipped with selective catalytic reduction (SCR) and oxidation catalyst systems.

Natural gas supply to the Project would be from the existing 16-inch diameter Ferndale Natural Gas Pipeline, which takes natural gas from the Westcoast Pipeline system near Sumas, Washington at the U.S./Canadian border and transports it to the Refinery and to the Alcoa Intalco Works Smelter. If supplemental natural gas is needed, it would be supplied from a third party pipeline, the connection to which would be located adjacent to the Project site near the Ferndale pipeline.

One diesel driven emergency generator about 1,500 kW in size will be installed to provide support system power to critical plant instrument and lubrication systems in the event that electric power is not available from the grid. A diesel driven firewater pump will be used to maintain firewater pressure in the event that the electric power is not available or firewater pressure is inadequate. The diesel firewater pump is anticipated to be about 265 horsepower in size. The emergency generator and firewater pump are proposed to be operated a maximum of 250 hours per year for routine maintenance and training purposes.

The diesel fuel for the firewater pump and emergency generator will have a sulfur content determined by the Federal on road specification diesel specification at the time of fuel purchase. The sulfur content currently is specified at less than 0.05%. That Federal sulfur specification is scheduled to be reduced to less than 15 ppm (0.0015%) in mid 2006.

Water cooling needs will be supplied from an induced draft, counter flow, multi-cell cooling tower. Emissions from the cooling tower are expected to consist only of PM₁₀. These emissions originate from the dissolved solids in the droplets of cooling water, called “drift,” that escape in the air stream exiting the cooling tower. High efficiency drift eliminators with a drift rate of 0.001% are proposed to be installed.

1.3. Cogeneration Operation And Integration With The Refinery

The Cogeneration Project integrates its operation with the Refinery to increase efficiency and reduce the consumption of and impacts to natural resources. The Cogeneration Project would supply steam and electricity to the Refinery, which would in turn recycle condensate back to the Cogeneration Project. This cogeneration plant steam supply would allow the Refinery to reduce the use of older, less efficient boilers thus reducing their emissions to the atmosphere.

The emissions reduction benefits of the cogeneration operation are real and are estimated in the BP Cherry Point Cogeneration Project Application for Site Certification, but are not relied upon for any air permitting activities such as the PSD or NOC process. The PSD and NOC permits analyze and permit the Project as if it is a stand alone combined cycle power plant.

1.4. New Source Performance Standards (NSPS)

The federal “Standards of Performance for Stationary Gas Turbines” 40 CFR 60 Subpart GG is applicable to the nitrogen oxides (NO_x) and sulfur oxides (SO₂) emissions from the combustion turbines. This NSPS limits NO_x emissions from the proposed project’s turbines to 103 parts per million dry volume (ppmdv) and SO₂ emissions to less than 150 ppmdv, both at 15% oxygen (O₂). Test methods for NO_x and sulfur emissions are specified. It requires determination of daily sulfur emissions monitoring by keeping track of fuel sulfur content and usage. It allows development of a custom fuel monitoring schedule that must be approved by the United States Environmental Protection Agency’s (EPA’s) Region 10. Note that application of the “top down” Best Available Control Technology (BACT) process creates NO_x and sulfur emission limits that are much lower than these NSPS maximum limits. There are no NSPS requirements for carbon monoxide (CO), particulates (PM), particulates less than 10 microns in diameter (PM₁₀), or volatile organic compounds (VOC) in Subpart GG.

The duct burners are subject to the NSPS for steam generating units in 40 CFR 60, Subpart Db. The NO_x emission limit for the duct burners is 0.20 lb/mmBtu.

No NSPS standards apply to the emergency generator or the firewater pump engine. Both are subject to the requirements for new nonroad engines in 40 CFR 89 that are applicable to their engine size class at the time of engine manufacture.

1.5. British Columbian And Canadian Air Quality Objectives

The federal Canadian Environmental Protection Act provides for three levels of air quality objectives: Desirable, Acceptable and Tolerable. British Columbia (BC) has similar “Objectives and Guidelines” for air quality comprised of three levels: A, B, and C. The federal objectives are based on the following definitions (the BC definitions are similar, but not identical):

- **Maximum Desirable** defines the long term goal for air quality and provides a basis for an antidegradation policy for the country for the continuing development of control technology.
- **Maximum Acceptable** is intended to provide adequate protection against effects on soil, water, vegetation, material, animals, visibility and personal comfort and well-being.
- **Maximum Tolerable** denotes time-based concentrations of air contaminants beyond which, due to a diminishing margin of safety, appropriate action is required without delay to protect the health of the general population.

The Project is not subject to these Canadian standards, but because of the close proximity of the site to the border with British Columbia, the Project’s Canadian impacts are analyzed and presented as a part of Section 3, the Ambient Air Quality Analysis, and Section 4 on Air Quality Related Values.

1.6. Project Emissions And PSD Applicability

The BP Cherry Point Cogeneration Project (Project) will be permitted as a major source.¹ Emission of a regulated pollutant² at levels considered significant³ by the federal PSD regulations require permitting

¹ Combined cycle turbines are considered part of the category “Fossil fuel-fired steam electric plants.” They are a major source under PSD regulations if they, in total, have the potential to emit more than 100 tons per year of a pollutant regulated by the PSD permitting program. WAC 173-400-113(1)(b)(i).

² The PSD program directly regulates a list of specific pollutants. These are referred to as “regulated pollutants.” The compounds listed in Table 1 are the regulated pollutants applicable to the project. PSD regulates other pollutants indirectly through the broad categories of “regulated” pollutants such as VOC and particulates. In Washington State EFSEC issues a second permit (the Notice of Construction Approval, or NOC) that complements the PSD permit and includes all emissions regulated by state and local regulations. WAC 173-400-113(1)(d)(i).

under the federal PSD program. As Table 1 shows, NO_x, CO, VOC, PM₁₀, SO₂, and sulfuric acid mist (H₂SO₄) are all emitted in PSD significant quantities.

After the application of emission controls representing BACT or to protect ambient air quality, the Project is proposed to have annual emissions as follows:

TABLE 1: Annual PSD Regulated Pollutant Emissions, Reflecting Proposed Emission Controls, and PSD Significant Emission Rate, all units are tons per year (tpy)

Equipment	Hours of operation per year	NO _x (tpy)	CO (tpy)	VOC (tpy)	PM ₁₀ ¹ (tpy)	SO ₂ (tpy)	H ₂ SO ₄ (tpy)
3 Turbines	8,760	229.4	156.8	42.2	254.4	50.9	35.5
Emergency Generator	250	3.4	0.9	0.16	0.09	0.0995	
Firewater Pump	250	0.42	0.021	0.018	0.006	0.0131	
Cooling Tower	8,760	0	0	0	7.2	0	
Total		233.3	157.7	42.3	261.6	51.0	35.5
PSD Significant Emissions Rate	Annual	40	100	40	15	40	7

1. All particulate matter is considered to be PM₁₀ for this project.

Emissions are subject to both short term and long term limits. Short term limits, such as hourly, three hour, or 24 hour averaging periods are usually larger in order to allow for fluctuations in the emissions of the measured pollutant. Long term limits, such as monthly or annual, reflect the more stable average emission rate over that longer time period. The annual averages include emissions from events such as start up and shut down.

BP has carefully analyzed estimated emissions for this project, and determined that annual emissions of NO_x, CO, PM₁₀, and SO₂ are best estimated for modeling and impacts analysis purposes at rates different than would be represented by multiplying the shorter term emission factors (such as hourly, three hour, or daily) factors by 8,760 hours or other appropriate annualizing factor. The annual emission rates calculated by BP are based on careful estimates of operating hours under maximum and reduced load conditions, the effect of startup and shutdown emissions, and the number of non operating hours. The annual emissions limits in this table are included in the permits.

³ The PSD regulations list a minimum annual emission rate for each regulated pollutant to be considered “significant” in WAC 173-400-113(1)(d)(i). Some of these threshold levels are given in Table 1.

Table 2: Annual Emission Limits on Individual Equipment

Unit	NO _x	CO	PM ₁₀	SO ₂
Each CTG/HRSG, tons/yr	77	53	85	17
Cooling Tower, tons/yr	NA ¹	NA ¹	7.2	NA ¹
Emergency Generator, tons/yr	3.4	NA ¹	NA ¹	NA ¹

1. NA means “not applicable.” The cooling tower has no NO_x, CO, or SO₂ emissions. The emergency generator’s NO_x emissions are the only emissions from the generator or the firewater pump estimated to be more than 1 ton per year.

Most toxic air pollutants that would be emitted by the project are a subset of the of the criteria pollutant emissions listed in Table 1. This includes toxic air pollutants listed as federal Hazardous Air Pollutants (HAPS) and those listed as Washington State Toxic Air Pollutants (TAPs). For example, most organic based toxic compounds are included as a subset of VOC compounds. Metal toxic compounds emitted to air are a part of the PM₁₀. Nitrogen oxide (NO, a state TAP but not a federal HAP) is a portion of the NO_x potential emissions estimate.

Toxic air pollutant emissions are estimated and their impacts are evaluated as part of the ambient air quality analysis in Section 3 of this Technical Support Document. Toxic emissions are regulated in the NOC portion of this EFSEC permit according to the Washington State regulation 173-460 WAC.

Ammonia would be used as part of the SCR NO_x control catalyst system. Ammonia is not a federal HAP, but is listed as a Washington State TAP. At the proposed maximum “slip” of 5.0 ppm_{dv}, total ammonia emissions to the atmosphere would be 173 tons per year. Ammonia and other toxic air pollutant emissions from the proposed Project that have modeled impacts are discussed in Section 3.2.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

2.1. Definition And Policy Concerning BACT

All new sources are required to utilize Best Available Control Technology (BACT). BACT is defined as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation, emitted from any proposed major stationary source or major modification, on a case-by-case basis, taking into account cost effectiveness, economic, energy, environmental and other impacts (40 CFR 52.21(b)(12)).

The "top down" BACT process starts by considering the most stringent form of emissions reduction technology possible, then determines if that technology is technically feasible and economically justifiable. If the technology is proven infeasible or unjustifiable, then the next less stringent level of reduction is considered. When an emission reduction technology meets the stringency, and technical and economical feasibility criteria, it is determined to be BACT.

2.2. BACT For Gas Turbine/Heat Recovery Steam Generator Systems

2.2.1. Nitrogen Oxides Control

NO_x is formed in two ways in a combustion process:

- The combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and
- The oxidation of nitrogen chemically bound in the fuel (fuel-bound NO_x).

Natural gas does not contain a significant amount of fuel-bound nitrogen, so all NO_x emissions from the gas turbines and duct burners are considered to originate from thermally formed NO_x.

2.2.1.1. Review of Previous BACT Determinations for NO_x

The lowest NO_x emission for CTs of similar size permitted listed in the EPA RACT/BACT/LAER Clearinghouse (RBLC) is 2.0 ppm. Of the six 2.0 ppm listings, five were Lowest Achievable Emission Rate (LAER) decisions made to allow location of power plants in areas with air quality ozone levels above the National Ambient Air Quality Standards. The sixth was the Goldendale Energy Inc. in Goldendale, Washington, which will be discussed later. Twenty five were listed with limits at 2.5 ppm NO_x, and 72 had limits between 3 and 5 ppm. These numbers reflect gas fired combined cycle turbines 25 MW or greater in size permitted over the last seven years that have been listed in this EPA clearinghouse as of October, 2003.

Other information sources (National Park Service personal contacts, the EPA Region 4 National Turbine List at www.epa.gov/region4/air/permits/index.htm California Energy Commission siting cases web site at www.energy.ca.gov/sitingcases/index.html) were searched. When actual permit details could be obtained for these recent permits, it was found that the 2.0 ppm NO_x limits often were applied as long term averages, such as annual. Larger shorter term NO_x limits (typically about 2.5 ppm or greater) were usually included as a part of the permitted limits. Many of these newly permitted plants had not been built yet.

In Washington State, at least seven combined cycle gas fired turbine power plants with turbine sizes similar to the proposed BP Cogeneration Project have been permitted within the last 7 years, four by EFSEC (Chehalis Generation Facility (Chehalis), Satsop CT Project (Satsop), Wallula Power Project (Wallula), and Sumas 2 Generation Facility (Sumas 2)), and three by Local Air Authorities (Clark Public Utilities River Road facility, Goldendale, and Mint Farm Generation). Sumas 2, Satsop, and Goldendale each had special considerations such as modeled impacts on Class I areas or other local issues that led the applicant to accept, or the permitting authority to impose, a more stringent NO_x short term limit of 2.0 ppm with either an averaging time of 3 or 24 hours. The balance of these permits had NO_x limits from 2.5 to 4.0 ppm_{dv}. The Chehalis and River Road projects are operational. Satsop and Goldendale are partially constructed. The rest have not commenced construction.

Annual NO_x emissions (tons per year) reported in the RBLC also reflect other NO_x environmental factors taken into consideration by the permitting authority. Per turbine NO_x annual emissions rates for recently permitted turbines in Washington state are 72 tpy (Sumas 2), 76.7 tpy (Goldendale), 106 tpy (Wallula), and 121.7 tpy (Satsop).

The formation of NO_x from the proposed CTs is minimized by the use of dry low NO_x combustors. These combustors control NO_x to 9 ppm_{vd} for the GE 7FA turbine under full load operating conditions and for loads down to 50 percent during natural gas firing. The HRSG is proposed to be equipped with low NO_x duct burners with a NO_x emission rate of 0.08 lb/mmBtu. To achieve lower levels of NO_x, add-on controls are required.

A review of the information available at the US EPA's RBLC, vendor inquiries, and contacts with regulatory authorities indicated that three potential additional NO_x control technologies should be considered: Selective Catalytic Reduction (SCR), SCONOXTM, and XONON. All three claim to reduce NO_x to 2 ppm, so they are considered equally stringent for this project. Other NO_x control technologies such as steam or water injection have been used in the past, but are not applicable to the current advanced dry low NO_x turbine combustors unless oil fuel is to be combusted in the turbines, which is not the case for this Project.

2.2.1.2. XONON

XONON is a catalytic process that reduces NO_x emissions within the turbine combustion zone by lowering the combustion temperature and hence the NO_x formation. Each XONON equipped turbine model requires a unique burner design. The first XONON burner has been commercially demonstrated on a Kawasaki 1.5 MW turbine. The owner of the process, Catalytica Energy Systems, has published news reports that XONON equipped combustors are currently being developed for use in several 5 to 10 MW sized turbines by other turbine manufacturers. Because XONON has not yet been developed for the GE 7FA combustor, it is not considered technically feasible for this project and is eliminated from further consideration as BACT.

2.2.1.3. SCONOXTM

SCONOXTM (SCONOX) is a developing control technology that has been given consideration by US EPA and state regulatory agencies as a potential emission control technology. SCONOX is a catalytic technique that simultaneously oxidizes CO to CO_2 , NO to NO_2 and then absorbs NO_2 onto the surface of a catalyst through the use of a potassium carbonate absorber coating. VOCs are also removed by the catalyst system. This control technique does not use ammonia. According to EmeraChem (formerly Goal Line Environmental Technologies), the vendor of SCONOX, SCONOX can achieve NO_x emissions down to 2 ppmdv.

This control technology has been demonstrated on smaller combustion turbines (approximately 1 to 40 MW) in California and Massachusetts. However, to date, there have not been any SCONOX systems installed on large CT applications such as that being proposed here. Additional technical uncertainties regarding the applicability of SCONOX technology to “F” class turbines have recently been raised by other permitting agencies. The US EPA Environmental Appeals Board (EAB) and the California Energy Commission (CEC), on May 30, 2001 issued simultaneous rulings on another project refusing to overturn a BACT decision by the Shasta County Department of Resource Management Air Quality Management District that the SCONOX technology is not technically feasible for turbines of the size being considered for the proposed BP Project. The District’s BACT decision said that there are several operational requirements associated with the SCONOX technology that makes it impractical as an emission control technology for ‘F’ Class turbines. It stated that all routine operating conditions were not covered in the SCONOX technology guarantee and that the guarantee would be voided if liquid water came into contact with the catalyst. Selective Catalytic Reduction (SCR) was the alternative BACT technology that was selected. For further information, see the “Three Mountain Power, LLC CEC Decision” and “EPA PSD Appeal No. 01-05 (May 30, 2001).”

A cost quote was obtained directly from EmeraChem to install SCONOX on this project. EmeraChem offers two price options:

1. The complete system can be purchased, which includes the mechanical equipment and the catalyst. The economic analysis concluded that the annualized cost to remove 195 tons per year of NO_x is \$33,800 dollars per ton.
2. The mechanical purchase/lease option allows the customer to buy the mechanical equipment and lease the catalyst. The annualized cost was estimated at \$22,900 per ton of NO_x removed.

Since SCONOX can remove NO_x , CO, and VOC simultaneously, the cost per total pollutant removed using SCONOX was determined. The economic analysis concluded that the annualized cost was \$18,100 per ton of pollutant (NO_x + CO + VOC) removed.

Because SCONOX's cost per ton of NO_x removal is greater than that of SCR (determined in the next section), and because of the technical uncertainties surrounding SCONOX, it is determined that SCONOX is not to be considered BACT for the control of turbine NO_x emissions for the BP Cogeneration project.

2.2.1.4. Selective Catalytic Reduction

SCR is a control technique that has been widely used for more than ten years in a large number of power generation applications, mainly for large gas turbine combined cycle power plants that include heat recovery steam generators. In an SCR system, ammonia is injected into the exhaust gas where it reacts with NO_x at a catalyst bed. The catalyst lowers the activation energy of the chemical reactions that take place in order to reduce ammonia and NO_x to nitrogen gas and water. SCR can provide 80 to 90 percent NO_x control.

The SCR catalyst reactor is typically of fixed bed design. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow. In this Project, where there is an HRSG used for heat recovery, the SCR unit would likely be installed between the superheater and the high pressure evaporator coils of the HRSG. The catalyst would be a typical vanadium titanium catalyst system, which has an operating temperature range of about 600 to 800°F.

Installation of a catalyst bed also causes a pressure drop of approximately 4 inches of water, which contributes to a loss in power output from the facility.

Sulfur content of the fuel is an additional concern for systems that employ SCR. Catalyst systems promote oxidation of sulfur dioxide to sulfur trioxide (SO₃), which combines with water to form sulfuric acid or reacts with excess ammonia to form ammonium salts.

The SCR process is also subject to catalyst deactivation over time due to physical deactivation and chemical poisoning of the catalyst. Catalyst suppliers typically guarantee a three year catalyst life for combustion turbine applications. Experience with SCR catalyst life in Washington State indicates that the actual service life of these SCR catalysts is at least twice that three year guaranteed life, and probably more. Power plants combusting only natural gas have had minimal problems with their SCR catalyst systems due to deactivation or contamination from sulfur compounds in the natural gas fuel.

The use of SCR technology will result in ammonia emissions to the atmosphere due to unreacted ammonia leaving the SCR unit. During normal operation, low levels of the NH₃ emissions occur because ammonia is added slightly in excess of the required amount to control the nitrogen oxides present in the exhaust. These ammonia emissions are referred to as "ammonia slip". As the catalyst degrades over time, ammonia slip will increase, ultimately requiring catalyst replacement. The ammonia slip design rate for the proposed Project is a maximum of 5 ppm and is expected to usually be lower in actual operation. Testing in Washington State confirms that the ammonia slip rate is typically much less than 5 ppm.

The desired level of NO_x emission reduction is a function of the catalyst volume and NH₃/NO_x ratio. For a given catalyst volume, higher NH₃/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in undesired increased levels of ammonia slip. It is important to note that the reduction of NO_x emissions to levels below 2.5 ppm may increase NH₃ emissions.

SCR has been demonstrated effective at numerous installations throughout the United States since the 1980's.

Capital costs for installation of an SCR system on each CT/HRSG were developed based on cost quotations obtained from Envirokinetics (Crites, July 2001). The overall removal efficiency is approximately 72 percent to achieve a NO_x level of 2.5ppm. SCR capital equipment includes the

catalyst, reactor, ammonia storage tanks, SCR control systems and instrumentation, and ammonia delivery system. Capital equipment cost is estimated at \$2,291,900. When the direct and indirect installation costs are added, the total capital cost is estimated at approximately \$4,604,400 for each turbine. Annual costs include addition of operating labor, annual catalyst replacement cost, maintenance, ammonia use. When these annual costs and the annualized capital costs are combined, the cost per CT of adding an SCR system to the dry low NO_x combustor is \$9,400 per ton of NO_x removed.

2.2.1.5. NO_x BACT Conclusion

Lean premix dry low NO_x combustors, low NO_x burners for the duct burners, plus SCR are considered to be NO_x BACT for this Project. The control system will control NO_x emissions from each combustion turbine heat recovery steam generator stack to 2.5 ppm_{dv}, 3 hour average, and 18.7 pounds per hour calculated on a 24 hour average.

Annual emissions for each turbine are limited to 77 tons per year. This is comparable or less than other recently permitted turbines in Washington State that had 2.0 ppm NO_x limits.

It is recognized that the use of cogeneration steam by the Refinery will reduce Refinery boiler steam production. These Refinery boiler emissions reductions are estimated to be large enough to result in a net decrease in the combined total NO_x emissions from the two sources when both are in normal operation. This NO_x reduction benefit is not a part of the PSD or NOC permits. The proposed Project's air emission impacts and all permit terms are determined for operation independent of the Refinery and do not depend on any emissions reductions that occur due to the Refinery's use of Project cogeneration steam.

2.2.2. Carbon Monoxide Control

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. CO is controlled by providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion. These control factors, however, can also result in higher emission rates of NO_x. Conversely, a low NO_x emission rate can be achieved through flame temperature control (by low-NO_x combustors) and can result in higher levels of CO emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping the CO emission rates at acceptable levels.

As discussed in the NO_x BACT section, this Project proposes to use GE 7FA turbines equipped with lean premix dry low NO_x burners, and duct burners equipped with low NO_x burners. These minimize CO emissions from the burners. The turbine can achieve 9 ppm_{vd} CO emissions at loads between 50 and 100% when firing natural gas without additional controls.

2.2.2.1. Review of Previous BACT Determinations for CO

The lowest CO emission for CTs of similar size permitted listed in the EPA RBLC is 2.0 ppm. Nine listings were at 2.0 ppm, one at 2.5 ppm, ten between 3.0 and 3.9 ppm, and 11 between 4.0 and 5.9 ppm. These numbers reflect the low range of CO limits for about 200 gas fired combined cycle turbines, 25 MW or greater in size, and listed in this EPA clearinghouse as of October, 2003. These low CO limits represent 31 of 200 listings, or about 15% of the listings. The majority of the limits were between 10 and 30 ppm, with a maximum of 200 ppm.

As described in the NO_x BACT discussion, in Washington State at least seven combined cycle gas fired turbine power plants with turbine sizes similar to the proposed BP Cogeneration Project have been permitted within the last 7 years. Four were permitted by EFSEC (Chehalis, Satsop, Wallula, and Sumas 2), and three by Local Air Authorities (Clark Public Utilities River Road facility, Goldendale, and Mint

Farm Generation). Four had short term CO limits of 2 ppm, and one had a 6 ppm short term limit. The Mint Farm CO limit was 6 ppm 1-hour average, but 2.0 ppm annual average.

A review of the information available at the US EPA's RBLC, vendor inquiries, and contacts with regulatory authorities indicated that two potential CO control technologies should be considered:

1. Catalytic Oxidation, and
2. SCONOx

Each of these technologies claims to be able to reduce CO to 2.0 ppmdv, so they are considered equally stringent for this project.

2.2.2.2. Catalytic Oxidation

An oxidation catalyst removes CO and organic materials from the turbine and duct burner exhaust stream by reacting them with oxygen in the hot gas stream to form carbon dioxide (CO₂). Platinum, or a mix of similar metals, is typically the active catalytic ingredient. Technical factors relating to the CO catalyst system include reactor design, optimal operating temperature, pressure loss to the system, and catalyst life.

The oxidation catalyst is usually located in the HRSG, downstream of the duct burner where the temperature is within 700 to 1,100°F. As the exhaust gas flows through the catalyst, it causes a pressure drop of approximately 1.5 inches of water, which contributes to a slight loss in power output. Catalyst systems are subject to loss of activity over time due to physical deactivation and chemical poisoning. Catalyst suppliers typically guarantee a three year catalyst life for combustion turbine applications. Experience with oxidation catalysts in Washington State indicates that the expected lifetime of an oxidation catalyst combusting natural gas should be more than twice this guaranteed 3 year lifetime.

An estimate for capital and annual costs associated with installation of an oxidation catalyst system on each GE 7FA CT/HRSG system was obtained from Envirokinetics (Crites, July 2001). The overall removal efficiency is approximately 78 percent to achieve a CO level of 2.0 ppm. The cost of basic equipment (including first catalyst load) was estimated at \$2,162, 900. Addition of direct and indirect installation costs raised the total estimated capital cost to \$4,338,100.

Addition of annual operating costs such as operating labor, routine inspection and maintenance, spent catalyst replacement, and lost cycle efficiency due to the increased backpressure give an annualized cost of \$12,800 per ton of CO removed. This cost is normally not considered reasonable for CO BACT in Washington. However, BP is proposing to voluntarily install more stringent CO emission controls such as a CO catalyst that reduces CO emissions to 2.0 ppmdv.

2.2.2.3. SCONOx

A technical analysis of SCONOx is presented in the previous Section 2.2.1.3 when discussing SCONOx as a NO_x control. See that section for a discussion of the SCONOx technical, environmental and economic impacts.

SCONOx results in an estimated cost of \$42,700 per ton CO removed for the complete system purchase option and \$28,900 for the mechanical purchase/catalyst lease option. As stated in the NO_x BACT discussion, for removal of multiple pollutants (total tons of NO_x + CO + VOC removed) the estimated annualized cost is \$18,100 per ton of pollutant removed.

As determined in the NO_x BACT section, because of SCONOX's high cost per ton of pollutant removal, and the technical uncertainties surrounding the process, it is determined SCONOX is not considered BACT for the control of CO emissions for the BP Cogeneration project.

2.2.2.4. CO BACT Conclusion

Lean premix turbine combustors, plus an oxidation catalyst are considered to be CO BACT for this Project. The control system will control CO emissions from each combustion turbine heat recovery steam generator stack to 2.0 ppmdv and 9.2 pounds per hour, both on a 3 hour average. An annual CO limit per of 53 tons per year per turbine is proposed by BP and accepted by EFSEC.

2.2.3. Volatile Organic Compounds (VOC) Control

Incomplete combustion of natural gas fuel results in emission of some unburned hydrocarbons. VOCs are by definition organic compounds that participate in atmospheric photochemical reactions. This excludes methane, ethane, and several other organic compounds that have negligible photochemical reactivity. Control of VOCs is first accomplished by providing good combustion practices such as adequate fuel residence time, good fuel/air mixing, and high temperature in the combustion device to ensure complete combustion. Add on control devices such as catalytic oxidation can control VOCs further.

The CO BACT conclusion determined that an oxidation catalyst was to be installed for CO emissions control. According to the CO oxidation catalyst vendor, an added benefit of the CO oxidation catalyst is that it can remove up to 30 percent of the unburned methane, ethane, and propane. The supplier also claimed that the CO catalyst could also remove up to 70 percent of smaller VOC compounds. Additional information from EPA supports the catalyst supplier's smaller VOC removal claim with data suggesting that the CO catalyst can remove smaller VOCs such as formaldehyde at approximately the same rate as it removes CO. This analysis conservatively assumes that the CO oxidation catalyst removes up to 30 percent of the VOC emissions from each CT/HRSG system, resulting in a maximum VOC emission rate of three pounds per hour from each unit.

The question then is whether additional controls are justified. The additional options are identical to those in the CO control technology analysis: addition of a second oxidation catalyst, or a SCONOX installation after the already approved CO oxidation catalyst. As before, both technologies claim to perform similarly in CO or VOC reduction, so they are considered equally stringent.

A search of the EPA RBLC and other available sources failed to find any permitted installation of additional VOC controls in series with a CO oxidation catalyst.

2.2.3.1. SCONOX

A technical analysis of SCONOX was presented in the NO_x BACT analysis. See that section for a discussion of SCONOX technical, environmental and economic impacts.

The installation of the SCONOX system would cost similarly to the cost presented in the NO_x BACT analysis discussion. The major difference is that it would now be treating only a maximum of 14 tons per year of VOC assuming 100% removal. This leads to a cost of \$443,000 dollars/ton of VOC removed. The technical uncertainties surrounding SCONOX are still valid. The high cost per ton of VOC reduced along with the technical uncertainties surrounding the SCONOX process combine to determine that SCONOX is not appropriate as an additional control for VOC.

2.2.3.2. Catalytic Oxidation

A technical analysis of catalytic oxidation was presented in the CO BACT analysis. See that section for a discussion of an oxidation catalyst's technical, environmental and economic impacts.

If an additional oxidation catalyst were to be installed, one that was designed specifically for VOC control, it would be at least as expensive as a CO oxidation catalyst. With the maximum of 14 tons per year of VOC emitted from each CT/HRSG system, the cost would be \$46,000 per ton assuming 100% removal. This high cost per ton puts consideration of an additional oxidation catalyst to reduce VOCs beyond that considered BACT by EFSEC.

2.2.3.3. VOC BACT Conclusion

BACT for VOC for this project is determined to be use of the CO oxidation catalyst to also reduce VOCs approximately 30 percent. No additional control such as a second oxidation catalyst bed in series is justified. VOC emissions are limited to 3.0 pounds per hour (24 hour average) from each turbine/HRSG exhaust stack.

2.2.4. Sulfur Dioxide and Sulfuric Acid Mist Control

Sulfur dioxide (SO_2) is formed exclusively by the oxidation of the sulfur present in fuel. Some of the SO_2 may be converted (oxidized) to SO_3 , which in turn can form sulfuric acid (H_2SO_4). The sulfuric acid can either be emitted as sulfuric acid mist, or it can combine with ammonia to form an ammonium sulfate or bisulfate salt.

It is important to note that sulfur compound emissions from the turbines are due to the sulfur content of the natural gas fuel. They are not controllable by good combustion practices like emissions of NO_x , CO, or VOC are. Sulfur is considered a "pass through pollutant." The permitted emission limits are based on the best information available to estimate the daily maximum and annual average sulfur content of the natural gas fuel. If at some future time the sulfur content of the natural gas fuel rises above the design estimates, this is beyond the control of the Project. Discussions have suggested that a preferred way to deal with this is to report any emissions in excess of the permitted SO_2 and H_2SO_4 limits that are due to increased sulfur in the natural gas fuel as unavoidable excess emissions. The alternative would be to set more generous permit limits for SO_2 and H_2SO_4 emissions. The SO_2 and H_2SO_4 permit limits have been modeled and their impacts analyzed as very protective of all National Air Quality Standards, PSD increments, and Air Quality Related Values.

2.2.4.1. Available Control Techniques:

The most stringent "front-end" SO_2 control method demonstrated for combustion sources is the use of low-sulfur fuel, such as natural gas. An available "back-end" control would be installation of a wet or dry scrubber.

2.2.4.2. Scrubbers

Wet or dry scrubbers are generally not applied to combustion turbines that combust low sulfur fuels like natural gas due to the very low SO_2 emissions and the high cost of a scrubber. An economic analysis was performed to estimate the cost of installing a wet scrubber on the combustion turbine/HRSG system. It estimated a cost of \$297,000 per ton of total SO_2 and H_2SO_4 removed. The RBLC does not list any add-on controls as BACT for sulfur compounds from any combustion turbine combined-cycle plants.

2.2.4.3. Low Sulfur Fuel

The next most stringent control is the use of low sulfur fuel such as natural gas. Natural gas supply to the Project would be from the existing 16 inch diameter Ferndale Natural Gas pipeline. The Ferndale pipeline obtains natural gas at the Northwest Pipeline Sumas Station. The sulfur content of the Northwest Pipeline natural gas is tested hourly at the Sumas Station. The Ferndale pipeline adds a sulfur based odorant at a rate of about 0.3 grains per 100 standard cubic feet (scf). The Project's natural gas fuel is expected to have a maximum daily average sulfur content of 1.6 grains per 100 scf of gas and an average annual sulfur content of no more than 0.8 grains per 100 scf.

2.2.4.4. Sulfur Dioxide and Sulfuric Acid BACT Conclusion

BP proposes and EFSEC agrees that the exclusive use of natural gas as fuel is BACT for controlling SO₂ and H₂SO₄ emissions from the combustion turbine/duct burners. SO₂ and H₂SO₄ emissions will be limited to 8.8 lb/hr and 2.8 lb/hr (24 hour average) respectively. Natural gas sulfur content will be determined on a daily basis based by fuel analysis information from the natural gas suppliers, then used with fuel consumption measurements to determine daily emissions of SO₂ and H₂SO₄ from each turbine/HRSG. Annual stack testing using EPA reference methods will provide a check on the sulfur in natural gas information provided by the supplier, and also determine how much sulfur is converted to sulfuric acid.

These limits on the emission of sulfur compounds also effectively limit the sulfur content of the natural gas that can be accepted by the Project. This makes additional sulfur content limits on the natural gas fuel duplicative and not necessary.

2.2.5. Particulate and Particulate Matter Less Than 10 Microns Control

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for particulate or for particulate matter less than 10 microns (PM₁₀) emitted from gas turbines.

Particulate matter (PM) is defined as fine solid or semisolid materials smaller than 100 microns in size. PM₁₀ is a subset of particulate and is defined as PM smaller than 10 microns in size. A third subset of PM is PM_{2.5}, which is PM smaller than 2.5 microns in size. PM_{2.5} is not specifically regulated as a particulate class by PSD or NOC permitting processes. PM_{2.5} emissions are considered in more detail in Section 3 of this document, in the context of air quality impacts in Canada.

Particulates from natural gas consumption are generally all considered to fit within the PM₁₀ range, and this permit assumes that. The EPA's AP 42⁴, indicates that almost all PM emissions from gas turbines fired on natural gas are below one micrometer in size. In the following sections of this document and in the accompanying PSD and NOC permits, all particulates will be referred to as PM₁₀, unless specific reference is otherwise made to PM_{2.5}.

Particulates from combustion are classified by a second property: whether they are solid particles in the combustion stack, or whether they form particles (condense) immediately when they cool after leaving the hot stack. The first type is called filterable because it can be collected on the surface of a mechanical filter. The particulates collected represent what is typically thought of as particulates, such as soil, unburned particles of fuel, or other solid materials. The second type of particle is called condensable, because these particles form (condense) immediately upon cooling after leaving the combustion stack. They are measured by a different test method that cools and absorbs them into a liquid.

⁴ AP 42, Section 1.4, Natural Gas Combustion, available over the internet from the EPA's Technology Transfer Network's CHIEF section at <http://www.epa.gov/ttn/chief/efinformation.html>

PM₁₀ emission levels from natural gas combustion are extremely low in mass as well as small in size. Testers are finding that flow samples must be taken for more than four hours just to get enough sample to measure in the EPA reference test methods. The particulate emission level achieved by combusting natural gas using good combustion practices in modern, well designed burners is comparable or even lower than control levels achievable by particulate control technologies such as bag filters, electrostatic filters, and venturi scrubbers. Particulate size and concentrations are below values for which vendors of such equipment are prepared to offer performance guarantees.

Some in the stack testing community are currently discussing and challenging the validity of these low particulate emission rate measurements, especially the condensable particulate test that typically represents more than 75% of the measured particulates. The issue is that the condensable particulate test method (EPA RM 202) creates a positive bias (indicates more condensable PM₁₀ than is actually emitted)⁵.

EPA has been addressing this condensable particulate measurement issue by developing Conditional Test Method CTM-039. CTM-039 was posted on the EPA Technology Transfer Network Emission Measurement Center web site (<http://www.epa.gov/ttn/emc/tmethods.html>) on June 5, 2003 and specified as available for use by Federal/State/Local agencies in permits and SIPs. CTM-039 is claimed to be appropriate for gas turbine particulate measurement, but it is a new method with little known history of use or proven applicability. Assuming that the Council makes a positive recommendation to the Governor, and the Governor approves this Project, and since the construction of the BP Cherry Point Cogeneration Project will not be completed for at least three years, it is intended by this permit writer that BP could submit materials justifying to EFSEC that CTM-039 or a similarly applicable method be allowed as an alternative method for particulate measurement as allowed in the PSD permit. In the interim, this draft approval requires measurement of particulates using the currently approved filterable and condensable particulate EPA Reference Methods.

No example of add on type particulate control for natural gas fueled combustion turbines or similar natural gas combustion sources could be found in the EPA RBLC, or from suppliers of control equipment. The particulate control measures that were found included combustion of a low ash fuel such as natural gas and use of good combustion practices in well designed combustion devices.

The small particulate size and low particulate emission level, along with the lack of any example of add on particulate controls, and lack of vendor performance guarantees for natural gas fired combustion units leads EFSEC to determine that add on controls for particulate are not technically feasible for this Project.

2.2.5.1. Particulate and PM₁₀ BACT Conclusion

BP proposes, and EFSEC agrees that BACT for PM and PM₁₀ is determined to be use of natural gas for fuel, and combustion of the natural gas using good combustion practices in lean premix dry low NO_x turbine burners and low NO_x duct burners. The proposed BACT emission limits are 20.6 pounds per hour, averaged over 24 hours for each turbine/HRSG. An annual limit of 85 tons per year (filterable plus condensable) is also proposed. Initial performance tests and annual testing using EPA reference methods is proposed annually for the first three years of operation. If these tests all show compliance, the annual testing may be reduced to once every five years. Failure of a test will require a retest and reinstate annual testing until another three consecutive years of testing show compliance.

⁵ "In-Stack Condensable Particulate Matter Measurements and Issues" Louis A. Corio and John Sherwell, Journal of Air & Waste Management Association, Volume 50, pages 207-218, February 2000.

2.2.6. Toxic Air Pollutants Control

Almost all of the toxic emissions from the proposed Project fall into the category of PM₁₀ or VOC. Ammonia falls outside each of these because it is a gas, but not a VOC. This means that the same controls that were considered in the earlier BACT discussions for PM₁₀ and VOC emissions are considered for toxic emissions other than ammonia.

2.2.6.1. PM₁₀ Toxic Air pollutants

Baghouses and electrostatic precipitators (ESPs) are frequently used to control PM₁₀ emissions for electrical generation facilities not fueled by natural gas, such as coal fired power plants. These PM₁₀ controls were determined technically infeasible in the PM₁₀ BACT Section 2.2.5 because particulates from natural gas combustion are so small (below 1 micron in size) that these controls can not efficiently remove them. See Section 2.2.5 above for a more complete discussion of these options. The arguments from that section apply equally well to the subset of these fine particulates that are toxic.

2.2.6.2. VOC Toxic Air Pollutants

VOC toxic emissions can be controlled by oxidation. As discussed in the VOC BACT Section 2.2.3, guidance indicates that an oxidation catalyst should control formaldehyde (the primary air toxic from natural gas combustion) to similar reduction levels as CO emissions. This means that the currently proposed CO oxidation catalyst will reduce formaldehyde emissions. The project emissions estimate conservatively assumes a 30% reduction in VOC due to the CO oxidation catalyst.

Turbine emissions testing for formaldehyde is required by the NOC air permit as part of the process to determine if the Project will be subject to the Federal Combustion Turbine NESHAP⁶ in 40 CFR 63 Subpart YYYY. The NOC portion of these air permits requires continuous monitoring of the oxidation catalyst inlet temperature and maintaining the inlet temperature to the oxidation catalyst within the range recommended by the catalyst manufacturer.

Formaldehyde testing on gas turbines is a new and developing science. Very few of these types of tests have been run. A gas turbine plant has to emit more than 10 tons per year of formaldehyde to have the Combustion Turbine NESHAP become fully applicable to it. The data available suggests that total emissions from the proposed project could be below that threshold.

2.2.6.3. Ammonia

Ammonia is not a Federal Hazardous Air Pollutant (HAP), but it is a State of Washington Toxic Air Pollutant listed in Chapter 173-460 WAC. Ammonia is used as a reactant in the SCR catalyst system to reduce NO_x emissions. See Section 2.2.1.4 which discusses both SCR and ammonia's part in the process. Ammonia that slips through the SCR catalyst bed is referred to as "slip." A search of the EPA RBLC database and the other permit information sources use for the NO_x BACT determination (Section 2.2.1.1) determined that the ammonia slip rate traditionally allowed has been 10 ppm_{dv} or lower. Recent permits have reduced that to 5 ppm_{dv}. The 5 ppm_{dv} slip limit is proposed for this Project.

A further discussion of turbine toxics emissions is found in Section 3.2 of this document.

⁶ Combustion Turbine NESHAP information is available from the US EPA at the web site <http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html>

2.2.6.4. Toxic Air Pollutants BACT Conclusion

BACT for Toxic Air Pollutants for this project is determined to be use of the CO oxidation catalyst to also reduce toxic VOCs. The CO catalyst inlet temperature will be monitored. Formaldehyde emission levels will be determined by testing. Ammonia emissions are limited to a maximum of 5 ppm_{dv} and 13.2 pounds per hour (both at a 24 hour average) from the Turbine/HRSG exhaust stack.

2.2.7. Turbine Startup And Shutdown Control

2.2.7.1. Description of startup and shutdown

Turbine startup is defined as any operating period that is ramping up from less than partial load. Partial load is when the turbine is operating at less than 60% of turbine power generation capacity. Startup ends when normal temperatures have been reached in both the catalytic oxidation and selective catalytic reduction modules. Normal operating temperatures for these two catalyst systems are recommended by the catalyst system manufacturer. The draft approval limits the time allowed for startups in case that these proper operating temperatures are not obtained within a reasonable time.

Shutdown starts when ramping down from normal operation (between 60 and 100% turbine power generation capacity), and ends when fuel flow ends.

Startups are classified into three types; hot starts, warm starts, and cold starts. Hot starts are those starts that occur less than 8 hours after the turbine has been shut down. Warm starts occur when the turbine is restarted after being shut down for 8 to 72 hours. Cold starts occur when the turbine is restarted after being shut down for more than 72 hours.

An integrated microprocessor based control system will be provided for the turbine equipment, for data acquisition, and for data analysis. The control system will be used for startup, shutdown, monitoring and control of emissions, and for protection of personnel and equipment. This assures that the turbine startups and shutdowns are carefully done to be safe, protect the equipment from damage, and minimize emissions. The startup procedure for a three turbine power block is staged, where the first turbine started heats the second and third turbine's equipment, effectively shortening the total startup time.

2.2.7.2. Emissions

The turbine manufacturer, General Electric, provided estimates of emissions during startup and shutdown. NO_x, CO, and VOC emissions increase during startup because the low NO_x turbine burners take time to stage into low NO_x operating mode, and because the SCR and oxidation catalysts are not up to operating temperature yet. PM₁₀ and SO₂ emissions are proportional to fuel flow, not combustion conditions, so their emission rate does not increase above permitted levels. The impact of NO_x, CO, and VOC emissions were modeled for startup and shutdown.⁷ Impacts were well below any air quality standard. The permit's time limits on startup and shutdown are very protective of these air quality standards. Tables 3 and 4 show the maximum modeled impacts in the U.S. and Canada respectively. NO_x and CO continuous emission monitors will be operational during startups and shutdowns to measure emissions.

⁷ Startup emissions were modeled after the Project's application was submitted. Startup and shutdown as well other modeling issues are discussed in the prefiled direct testimony of Brian R. Phillips, Exhibit 22.

Table 3: Maximum Modeled Impacts in the U.S. From Startup

Pollutant	Averaging Time	Maximum Concentration ($\mu\text{g}/\text{m}^3$)			Lower of WAAQS or NAAQS ($\mu\text{g}/\text{m}^3$)
		Modeled	Background	Total	
SO ₂	24-hour	0.6	13	14	260
	3-hour	3.2	27	30	1,300
	1-hour	4.1	35	39	1,065
PM ₁₀	24-hour	1.6	35	37	150
PM _{2.5}	24-hour	1.6	29	31	65
CO	8-hour	47	2,668	2,715	10,000
	1-hour	584	2,900	3,484	40,000

Background concentration is the maximum value for each pollutant and averaging time of the two nearest representative ambient measuring stations (see Application for Site Certification Tables 3.2-8 and 3.2-9).
In the United States, there is no short-term (24-hour or 1 hour) NAAQS for NO₂.
Excludes the effect of Refinery emissions reductions.

Table 4: Maximum Modeled Impacts in Canada From Startup

Pollutant	Averaging Time	Maximum Concentration in Canada ($\mu\text{g}/\text{m}^3$)			Most Stringent Canadian Objective or Standard ($\mu\text{g}/\text{m}^3$)
		Modeled	Background	Total	
SO ₂	24-hour	0.6	16	17	150
	3-hour	2.5	27	30	374
	1-hour	3.3	59	62	450
PM ₁₀	24-hour	1.5	35	37	50
PM _{2.5}	24-hour	1.5	18	20	30
CO	8-hour	27	2,668	2,695	5,500
	1-hour	340	2,900	3,240	14,300
NO ₂	24-hour	2.0	69	71	200
	1-hour	87.4	107	194	400

Notes:
PM_{2.5} emissions are conservatively assumed to be equal to PM₁₀ emissions.
The PM_{2.5} Canada-wide standard is based on the 98th percentile averaged over 3 years, therefore the modeled and background values indicated above are also based on these assumptions.
NO_x is considered to be fully converted to NO₂.
Excludes the effect of Refinery emissions reductions.

The permit application was prepared and emissions estimated by assuming 100 hot starts and 100 shut downs per year. Emissions from these startup and shutdowns were used to develop the annual per turbine pollutant emissions estimates and limits. The short term (hourly and 24 hour average) and long term (12 month rolling average) emissions during startup and shutdown were modeled. Tables 3 and 4 show the short term impacts. Measuring and counting the startup and shutdown emissions towards the annual emissions is appropriate also. The NO_x and CO annual limits effectively limit the number of startups and shutdowns to the emissions modeled in the application.

2.2.7.3. Startup and Shutdown BACT Conclusion

BACT for startups and shutdowns is to follow the startup and shutdown procedures that are developed by the equipment manufacturers and documented by BP in the equipment Start-up, Shutdown, and Malfunction Procedures Manual required by PSD permit Approval Condition 13. Startups will end when

one of two events occurs: either the turbine(s) are operating above 60% load and normal operating temperatures have been reached in both the catalytic oxidation and selective catalytic reduction modules as indicated by the above referenced manual, or else two (2), four (4), or six(6) hours have elapsed since fuel was first introduced to the turbines on a hot, warm, or cold start respectively. Normal operating limits for NO_x, CO, and VOC are relieved while in startup or shutdown mode, but these and all emissions are measured and counted toward annual emissions. Annual emission limits on emissions of NO_x and CO limit the quantity of startup and shutdown generated emissions.

2.3. Cooling Tower

2.3.1. Description of Cooling Tower System

Cooling needs will be supplied by an induced draft, counter flow, multi-cell cooling tower. In this type of cooling tower, fans at the top of each cooling tower cell maintain a flow of air through the cooling tower. Circulating water pumps move the water from the steam condenser, where it picks up heat, to the top of the cooling tower. At the top of the cooling tower, the warm water is distributed onto a perforated deck. The water then falls through the perforations and is cooled by evaporation as it fall through baffles (called “fill”) to a basin at the bottom of the tower. Cool water from the cooling tower basin is returned to the condenser via the circulating water pumps.

2.3.2. Emissions

Emissions from the cooling tower are expected to consist only of PM₁₀. These emissions originate from the dissolved solids contained in droplets of cooling water, called “drift,” that escape in the air stream exiting the cooling tower. The magnitude of drift loss is influenced by the number and size of droplets produced within the cooling tower, which in turn are determined by the fill design, the air and water patterns, and the efficiency of the drift eliminator.

Drift eliminators are incorporated into the tower design to remove as many droplets as practical from the air stream before the air exits the tower. PM₁₀ emissions from cooling towers are usually estimated by using the tower’s design drift rate and the Total Dissolved Solids (TDS) concentration of the tower’s incoming cooling water. A high efficiency drift eliminator with a drift rate of 0.001 percent is proposed for the Project. Only one lower drift rate permit was found (0.0005%), but that was a LAER decision for a project sited in a particulate non attainment area, not a BACT decision.

2.3.3. Cooling Tower BACT Conclusion

BP proposes, and EFSEC agrees, that installation and operation of drift eliminators with a drift loss rate of 0.001% of the recirculating flow rate constitutes BACT for the cooling tower. Initial compliance will be based on submission of a copy of the drift eliminator manufacturer’s certification that the drift eliminators are installed in accordance with its installation criteria.

BP is required to submit to EFSEC a methodology they will use to estimate PM/PM₁₀ emissions from the cooling tower. The methodology shall be reviewed and approved by EFSEC prior to the first operation of the cooling tower. PM₁₀ emissions shall be limited to 7.2 tons per year on a rolling annual average, estimated monthly.

Routine compliance will be to use the calculation methodology once each quarter to estimate the PM/PM₁₀ emissions from each cooling tower. Emissions shall be reported in each quarterly emissions report.

2.4. Emergency Generator And Firewater Pump

2.4.1. Description of Emergency Generator and Firewater Pump

One diesel driven emergency generator about 1,500 kW in size will be installed to provide support system power to critical plant instrument and lubrication systems in the event that electric power is not available from the grid. A diesel driven firewater pump will be used to maintain firewater pressure in the event that electric power is not available or firewater pressure is inadequate. The diesel firewater pump is currently anticipate to be a John Deere Model 6081A engine (or equivalent) rated at 265 brake horsepower (bhp).

2.4.2. Emissions

The diesel engines will be of latest design, and meet the new engine specifications for either 2004 or the year of purchase, which ever is later. This minimizes the NO_x, CO, VOC, and PM emissions by using a well designed engine with good combustion design. The SO₂ emissions from the diesel engines will be minimized by using on road specification diesel fuel. The sulfur content of on road specification diesel oil is currently limited to less than 0.05% by federal regulations in 40 CFR Section 80.29(a)(i). In mid 2006 the sulfur content limit for on road specification diesel fuel is scheduled to be reduced to less than 15 ppm (0.0015%).

The emergency generator and firewater pump are proposed to be operated only for their intended emergency uses, and for limited testing and training periods. The hours of operation necessary for these purposes is estimated to be less than 250 hours per year, so the emissions from these units were estimated and evaluated for both a full 24 hour period, and for 250 hours per year total. Emission factors for new engines that meet current federal engine standards were used. Expected annual emissions for pollutants were listed earlier in Table 1.

2.4.3. Emergency Generator and Firewater Pump BACT Conclusion

BP proposes, and EFSEC agrees that the limitation to 250 hours of operation, purchase of the latest designed engines, and use of on road specification diesel fuel is BACT for the emergency generator and firewater pump. NO_x emissions from the emergency generator are limited to 3.4 tons per year on a 12 month rolling average. SO₂ emissions will be determined by calculations based on hours of operation and diesel fuel sulfur content. All other emissions from these units are estimated to be less than one ton per year, and are not required to be reported.

3. AMBIENT AIR QUALITY ANALYSIS

3.1. Regulated Pollutants

The PSD permitting program requires that an ambient Air Quality Impacts Analysis (AQIA) be made for pollutants emitted in significant quantities. As shown in Section 1.6 of this Technical Support Document, nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), particulates less than 10 microns (PM₁₀), sulfur dioxide (SO₂), and sulfuric acid mist (H₂SO₄) are all emitted in PSD significant quantities from this project.

An air quality analysis can include up to three parts: Significant Impact analysis, National Ambient Air Quality Standards (NAAQS) analysis, and PSD Increment analysis. The first step in the air quality analysis is to determine if emissions from the proposed project result in impacts greater than the modeling significance levels (MSLs). Then, for those pollutants and averaging periods that have impacts greater than the MSL, a NAAQS analysis is used to determine if the proposed project will cause or contribute to an exceedance of a NAAQS. The PSD Increment analysis is used to determine if the change in the Air Quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels.

3.1.1. Modeling Methodology

Two different models were used to determine the project's effect on air quality. The Industrial Source Complex model (ISC-Prime) was used to determine pollutant concentrations within a 50 kilometer by 50 kilometer area surrounding the project site. The CalPuff model was used to model for the visibility analysis in the Class I areas and in Canada. The modeling was done according to a Modeling Protocol agreed to by the Project's modeling consultant (Air Permits.com), the Department of Ecology's modeler (Clint Bowman), and the National Park Service and National Forest Service modeling technical staff.

The ISC-Prime dispersion model used (BEEST Version 8.93) was provided by Bowman Environmental Engineering (BEE). The model includes both the current ISCST3 model and its variant, the ISC Prime model (BEE Version 03002). The BP Refinery operates an on site meteorological measurement program that collects PSD quality meteorology data. Hourly meteorological data for the 1995, 1996, 1998, 1999, and 2000 calendar years was used. Data from 1997 was excluded because it was incomplete. Modeling was done for cold (5°F), average (50°F), and warm (85°F) temperatures.

The Cal Puff model is preferred for evaluating impacts beyond 50 kilometers. As all of the Class I areas are more than 50 kilometers from the proposed project, CalPuff was used for the Class I SIL analysis and AQRV analysis. CalPuff is a multi-layer, multi-species, non-steady-state puff dispersion model that simulates the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CalPuff version 5.4, provided by Earth Tech Inc., was used. One year of MM5 data (supplied by the University of Washington) from April of 1998 through February of 1999 was used in conjunction with data from 25 National Weather Service (NWS) surface meteorological stations to develop the meteorological field using CalMet, which is part of the CalPuff modeling system. Terrain data and land use data was obtained from the USGS website at <http://edc.usgs.gov/geodata/>.

3.1.2. Modeling Results

The results of the dispersion modeling analysis for Class I and Class II pollutant concentrations show that no Class I or Class II SIL is expected to be exceeded under the "worst case" emission scenarios. EPA and Washington State use these SILs as a screening threshold. Because all modeled impacts are below their respective SILs, no further dispersion modeling is required to demonstrate compliance with air quality standards and PSD increments. Table 5 shows the modeling results and the corresponding SILs.

Table 5: Significant Impact and Pre-Construction Monitoring Modeling Results

Pollutant	Averaging Period	Class II Areas			Class I Areas	
		Modeled Maximum Concentration (µg/m ³)	Modeling Significance Level (µg/m ³)	Monitoring De Minimus Concentrations (µg/m ³)	Modeled Maximum Concentration (µg/m ³)	Modeling Significance Level (µg/m ³)
NO _x	Annual	0.6	1	14	0.0053	0.1
CO	8-hour	50.4	500	575	--	--
	1-hour	81.4	2,000	--	--	--
PM ₁₀	Annual	0.25	1	--	0.0054	0.2
	24-hour	4.3	5	10	0.087	0.3
SO ₂	Annual	0.03	1	--	0.001	0.1
	24-hour	4.3	5	13	0.021	0.2
	3-hour	8.4	25	--	0.048	1.0
Notes: Excludes the effect of Refinery emissions reductions.						

The impact of the Project's emissions on Canada were modeled and are presented in Table 6.

Table 6: Project Maximum Impact on Canada

Pollutant	Averaging Time	Maximum Concentration in Canada ($\mu\text{g}/\text{m}^3$)			Most Stringent Canadian Objective or Standard
		Modeled	Background	Total	
NO ₂	Annual	0.2	27	27	60
	24-hour	1.6	69	71	200
	1-hour	16.7	107	124	400
CO	8-hour	4.8	2,668	2,673	5,500
	1-hour	13.6	2,900	2,914	14,300
PM _{2.5}	24-hour	0.9	18	19	30
PM ₁₀	Annual	0.2	13	13	30
	24-hour	2.5	35	38	50
SO ₂	Annual	0.03	3	3	25
	24-hour	0.7	16	17	150
	3-hour	3.3	27	30	374
	1-hour	5.3	59	64	450

Notes:
PM_{2.5} emissions are conservatively assumed to be equal to PM₁₀ emissions.
The PM_{2.5} Canada-wide standard is based on the 98th percentile averaged over 3 years, therefore the modeled and background values indicated above are also based on these assumptions.
NO_x is considered to be fully converted to NO₂.
Excludes the effect of Refinery emissions reductions.

These modeling results indicate that the maximum impact of the project in Canada is lower than the impact in Washington State. Impacts are well below current background concentrations, and a small percentage of each pollutant's most stringent Canadian Objective or Standard.

3.2. Toxic Air Pollutants

EFSEC requires an ambient air quality analysis of toxic air pollutants (TAPs) emissions in accordance with WAC 173-460 "Controls for New Sources of Toxic Air Pollutants". The TAPs are evaluated for both acute (24 hour) and chronic (annual) effects as required by the regulation. The quantities of all TAPs known to be emitted from the turbines and duct burners, and diesel engines were estimated and screened against the small quantity emission rates in WAC 173-460.

TAP emissions exceeding the small quantity emission rate exclusion were modeled to determine their maximum ambient concentrations. These maximum ambient concentrations were compared to the respective acceptable source impact levels (ASIL) listed in WAC 173-400-150 and 160. These ASILs are not health effect levels, but conservative thresholds that, if exceeded, indicate the need for further investigation of the effects of the TAP on ambient air quality and human health. Table 7 compares the TAPS modeled, the modeled concentration impacts, and their respective ASIL.

Table 7: Toxic Air Pollutants Significant Impact Modeling Results

Pollutant	Maximum Predicted Concentration ($\mu\text{g}/\text{m}^3$)		ASIL ($\mu\text{g}/\text{m}^3$) ³	ASIL Exceeded (Yes/No)
	Annual ¹	24-hr ²		
Acetaldehyde	0.00014	NA	0.45	No
Acrolein	NA	0.0027	0.02	No
Ammonia	NA	2.76	100	No
Benzene	0.00032	NA	0.12	No
1,3-Butadiene	0.00001	NA	0.0036	No
Formaldehyde	0.00237	NA	0.077	No
PAH	0.00007	NA	0.00048	No
Arsenic	0.00007	NA	0.00023	No
Beryllium	< 0.00001	NA	0.00042	No
Cadmium	0.00001	NA	0.00056	No
Chromium	NA	0.0024	1.7	No
Cobalt	NA	0.0018	0.33	No
Copper	NA	0.0018	0.3	No
Manganese	NA	0.0018	0.4	No
Nickel	0.00011	NA	0.0021	No
Zinc	NA	0.0025	7	No
Sulfuric Acid	NA	0.57	3.3	No
1. Highest of annual cases 1AB, 1BB, 1CB, 2B, 6B (at 50°F). 2. Highest of all cases for 1995, 1996, 1998, 1999, 2000. 3. Acceptable source impact levels (ASIL).				

The recently signed Combustion Turbine NESHAP (40 CFR 63 Subpart YYYY) recognizes that the HAP emitted in the largest quantity from a combustion turbine burning natural gas is formaldehyde. The formaldehyde limit in the NESHAP is a concentration of 91 parts per billion in the turbine's exhaust, adjusted to 15% oxygen. The CO oxidation catalyst proposed for this project is also the preferred control under the NESHAP. The best evidence available indicates that the oxidation catalyst will reduce formaldehyde emissions similarly to CO.

The provisions of the NESHAP are permitted in the NOC portion of this permit. BP will test for formaldehyde emissions levels to determine the level of NESHAP applicability. If emissions are less than 10 tons per year (as expected by this permit writer), BP will be required to monitor the oxidation catalyst operating temperature the same as it would have under the NESHAP's provisions to continuously indicate that the catalyst is operating properly. Testing will be required once every five years. If formaldehyde emissions are greater than 10 tons per year, then formaldehyde testing will be required annually by the NESHAP. Testing for formaldehyde emissions is fairly new on a national basis, and has not been required by previous turbine permits in Washington State. The formaldehyde test method approved is Test Method 320 of 40 CFR 63, Appendix A.

Since there were no TAPS that exceeded their ASIL screening values, no additional toxics review is required. Because of this, EFSEC concludes that no adverse health impacts are expected to occur due to the increase in toxic pollutants emitted from the Project.

3.3. Ammonia Emissions

Ammonia emissions from the BP Project deserve special discussion. Ammonia is a TAP defined in WAC 173-460. Unreacted ammonia is released from the SCR process because a slight excess is required to reduce NO_x emissions down to the desired levels. The excess ammonia is called "ammonia slip".

Ammonia slip can be used as an indicator of SCR catalyst activity. High slip indicates poor operational control or degraded catalyst activity, resulting in higher NO_x emissions. SCR manufacturers have traditionally guaranteed that this slip of unused ammonia will be less than 10.0 ppm and occasionally as low as 5 ppm. Recent operating experience indicates that ammonia slip may be maintained at rates consistently below 5 ppm⁸ for a number of years after the initial start of the plant's operation. BP has agreed to this new, lower ammonia slip limit. The air toxics modeling in Table 5 show that modeled maximum ammonia impacts will be well below the ammonia ASIL found in 473-460 WAC.

EFSEC concludes that 5.0 ppm ammonia emission limits for the BP Cherry Point Cogeneration Project does not threaten human health and is appropriate for the Project.

4. AIR QUALITY RELATED VALUES

4.1. Visibility Impacts

Two different visibility analyses were done for visibility, one for the U.S. and one for Canada. Both analyses were performed using the CalPuff modeling procedure described in Section 3.1.1. The U.S. evaluation focused on the visibility at Class I areas, while the Canadian analyses focused on specific lines of site identified by the air quality staff of the Greater Vancouver Regional District (GVRD).

Visibility in the Class I areas in the U.S. was performed with the CalPuff model. PM₁₀, NO_x, and SO₂ were modeled, with chemical transformations of secondary pollutants such as ammonia nitrate and ammonia sulfate, and the results were combined to calculate a visibility coefficient. The results were then compared with background data to find a visibility change, in percent. The federal land managers consider over 5% to be a perceptible change in visibility and over 10% to be unacceptable.

Table 6 shows that the project emissions predict one day at one Class I area (Olympic National Park) has a visibility change over 5%. The National Park land managers were consulted about this perceptible change, and considered it acceptable.

BP also modeled visibility impacts considering reduction in emissions from the Refinery boilers and the net visibility impact considering those reductions. This was not relied upon for any PSD or NOC permitting, but is presented in Table 8 for informational purposes only.

Table 8: Visibility Impacts on U.S. Class I Areas

Class I area	Maximum Visibility Change (%)	Number of days over 5%	Maximum Visibility Change including Boiler Emissions Reductions	Number of days over 5%
Olympic National Park	6.0	1	1.9	0
North Cascades National Park	2.6	0	1.5	0
Alpine Lakes Wilderness Area	4.1	0	2.3	0
Glacier Peak Wilderness Area	4.4	0	2.1	0
Pasayten Wilderness Area	1.8	0	1.2	0
Mt. Baker Wilderness Area	4.1	0	2.3	0

Visibility modeling in Canada was performed differently. The calculated visibility coefficient was averaged over a line of sight, generally from a valley floor to a mountain peak. The modeled lines of sight

⁸ For example: PGE Coyote Springs in Morrow County, Oregon and Hermiston Generating Project, Umatilla County, Oregon operate at less than 4.4 ppm ammonia slip with NO_x below 4 ppm. Also see Selective Catalytic Reduction Control of NO_x Emissions, prepared by the Institute of Clean Air Companies, 1660 L St., Suite 1100, Washington, D.C., page 12 (1997).

were established by GVRD. The modeled visibility was compared with background data to determine if any additional days will have impaired visibility as compared to current conditions. Table 9 shows that the project will have no detrimental impact on visibility along these lines of sight.

Table 9: Visibility Impacts on Canadian Lines of Sight

Line of Sight	Number of days with impaired visibility, background conditions	Additional days with impaired visibility due to Cogeneration Project	Maximum visibility change
1	171	0	1.2%
2	166	0	2.4%
3	166	0	2.1%
4	166	0	2.2%
5	166	0	2.7%
6	166	0	1.5%
7	166	0	1.4%

4.2. Deposition Impacts

The National Park Service and the US fish and Wildlife Service have developed guidance on what levels of nitrate and sulfate deposition increases due to a single source would cause them to perform more detailed reviews of the impacts of the deposition within their Class 1 areas. The threshold established by these agencies is 5 grams/hectare/year. The maximum predicted nitrogen deposition level is 0.67 g nitrate/hectare/year in the Mt. Baker Wilderness Area. The maximum predicted sulfate deposition level is 0.73 g sulfate/hectare/year in the Alpine Lakes Wilderness Area.

Table 10: Deposition Impacts on Class I Areas

Class I area	Nitrogen Deposition g/ha/yr	Sulfur Deposition g/ha/yr
Olympic National Park	0.09	0.12
North Cascades National Park	0.47	0.32
Alpine Lakes Wilderness Area	0.60	0.73
Glacier Peak Wilderness Area	0.44	0.34
Pasayten Wilderness Area	0.24	0.14
Mt. Baker Wilderness Area	0.67	0.60
Threshold	5	5

4.3. Soils And Vegetation Impacts

Project emissions that have the most potential to affect soils and vegetation are those that contain either sulfur or nitrogen. As shown in Table 5 of Section 3.1.2, the maximum modeled impacts of these emissions are well below all federal permitting modeling and monitoring significance levels. These levels are intended to be protective of soil and vegetation as well as human health. Other ambient monitoring data (tests to measure the concentration of NO_x and SO₂ in normal background air) show that the annual modeled concentrations of SO₂ and NO₂ are only 1 and 2 percent respectively of their current annual average background levels at their impact area. Another measure of their impacts is that their maximum predicted concentrations are at least two orders of magnitude (100 times) below their National

Ambient Air Quality Standards. Investigation of land use shows that most of the land surrounding the Project is or has been used as agricultural land.

To summarize, the air quality analysis, conducted as part of this permit action, demonstrates that the facility does not cause or contribute to any violation of the NAAQS. Based on the NAAQS analysis and further analysis of the modeling of emissions, it is concluded that this project should produce negligible impacts on soils and vegetation.

4.4. Construction And Growth Impacts

The project site is within an area already zoned for Heavy Impact Industrial Use. During the anticipated 2-year construction period, the peak construction work force could be about 670 people. For daily operation and maintenance of the facility, about 30 full time staff may be required.

The proposed Project may cause a temporary increase in emissions related to the actual construction activities. The internal combustion engines on the construction vehicles and equipment may emit small amounts of PM, CO, SO₂, NO_x, and VOC. Fugitive PM emissions may also result from demolition, construction-related traffic, and other construction-related activities. BP will minimize fugitive PM emissions that extend beyond plant boundaries through appropriate fugitive dust control techniques.

Air quality and visibility impacts due to growth-related activities associated with the proposed facility are expected to be minimal.

5. CONCLUSION

The project will have no significant adverse impact on air quality. The Washington State Energy Facility Site Evaluation Council finds that the Applicant, BP West Coast Products, LLC, has satisfied all requirements for a Notice of Construction and PSD approval for the BP Cherry Point Cogeneration Project.

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